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Decision **ALTERNATE DECISION OF COMMISSIONER LYNCH**
(Mailed 02/13/2003)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the
Implementation of the Suspension of Direct
Access Pursuant to Assembly Bill 1X and
Decision 01-09-060.

Rulemaking 02-01-011
(Filed January 9, 2002)

ORDER ADOPTING COST RESPONSIBILITY SURCHARGE MECHANISMS FOR CUSTOMER GENERATION DEPARTING LOAD

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**ORDER ADOPTING COST RESPONSIBILITY
SURCHARGE MECHANISMS FOR
CUSTOMER GENERATION DEPARTING LOAD**

I. Introduction

Today's decision adopts policies and mechanisms to implement cost responsibility surcharges applicable to "Departing Load" served by "Customer Generation" within the service territories of California's three major electric utilities: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E). As the basis for this order, we reject the Settlement Agreement offered jointly by a number of parties to this phase of the proceeding as explained herein. We do, however, find that to be consistent with Pub. Util. Code Section 2827, net metered customers are only required to pay the DA CRS on the net energy consumption. As such, we reaffirm the provisions of Pub. Util. Code Section 2827 and ensure that customer generation eligible for net metering are only imposed DA CRS components on the net metered energy. Additionally, in order to encourage compliance with air quality standards established by the State Air Resource Board, for clean & ultra-clean distributed generation we find that it is appropriate to assign a zero cost fair share of DA CRS.

"Departing load" (DL), as used in this order, refers to that portion of the utility customer's electric load for which the customer: (a) discontinues or reduces its purchase of bundled or direct access service from the utility; (b) purchases or consumes electricity supplied and delivered by "Customer Generation" to replace the utility purchases; and (c) remains located physically at the same location or elsewhere within the utility's

service territory as of the date on which this Commission decision becomes effective. Reduction in load qualifies as DL as referenced in this order only to the extent that such load is subsequently served with electricity from a source other than the utility. This definition generally conforms to utility tariffs. This order does not address any other forms of DL such as that served by municipally-owned utilities or irrigation districts.¹

“Customer Generation” as used in this order refers to cogeneration, renewable technologies, or any other type of generation that (a) is dedicated wholly or in part to serve a specific customer’s load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer’s affiliates and/or tenant’s, and/or not more than two other persons or corporations. Those two persons or corporations must be located on site or adjacent to the real property on which the generator is located. Parties also use the terms “distributed generation,” “onsite and over-the-fence generation,” and “self-generation” as being interchangeable with “Customer Generation.”

The surcharges to be implemented pursuant to this decision are required to hold DL served by Customer Generation responsible for its share of the categories of costs set forth herein, and to prevent such costs from being unlawfully and unfairly shifted to bundled utility customers. The surcharge categories addressed in today’s order cover the following:

1. Costs associated with procurement of power by the California Department of Water Resources (DWR), with separate charges for:

¹ Nothing in this order should be construed as prejudging or limiting what Commission positions or treatment may be adopted for any other form of DL not covered in this order.

- (a) Historic shortfalls financed through a Bond Charge; and
 - (b) Forward costs associated with the ongoing power charges
2. Costs associated with the Historic Procurement Charge (HPC) (applicable to the SCE service territory only) pursuant to Decision (D.) 02-07-032, as modified by D.03-02-035.
 3. Tail” Competition Transition Charge pursuant to Pub. Util. Code Section 367(a).²

As a context for resolving the issues addressed herein, we review the background leading to this order. This proceeding was opened to address issues relating to the suspension of Direct Access (DA). We suspended the right to acquire DA pursuant to legislative directive, as set forth in Assembly Bill (AB) No. 1 from the First Extraordinary Session (AB 1X). (See Stats. 2002, Ch. 4.) This emergency legislation was enacted to respond to the serious situation in California when PG&E and SCE became financially unable to continue purchasing power due to extraordinary and unforeseen increases in wholesale energy prices.

The Governor’s Proclamation of January 17, 2001,³ and AB 1X required that DWR procure electricity on behalf of the customers in the service territories of the California utilities.⁴ As part of its provisions to

² All statutory references are to the Public Utilities Code, unless otherwise noted.

³ On January 17, 2001, Governor Davis issued a Proclamation that a “state of emergency” existed within California resulting from unanticipated and dramatic wholesale electricity price increases.

⁴ This authority ended on December 31, 2002.

deal with California's energy crisis, AB 1X also called for the suspension of the right to acquire DA, as set forth in Section 80110 to the Water Code.

In compliance with this mandate, the Commission ultimately issued D.01-09-060, suspending the right to acquire DA on or after September 21, 2001. In D.01-09-060, we stated, however, "that we may modify this order to include the suspension of all direct access contracts executed or agreements entered into on or after July 1, 2001." (D.01-09-060, pp. 8-9.)

On January 14, 2002, the instant Rulemaking (R.) 02-01-011 was initiated to consider among other things, whether a suspension date earlier than September 20, 2001 should apply to DA.⁵ On March 27, 2002, we issued D.02-03-055, determining that the DA suspension date should remain in effect as "after September 20, 2001." In D.02-03-055, we also required that bundled service customers not be burdened with additional costs due to cost shifting from the significant migration of customers from bundled to DA load between July 1, 2001 and September 21, 2002. We subsequently clarified that prevention of cost shifting meant that "bundled service customers are indifferent."⁶

Proceedings were initiated to implement the necessary charges on DA load to prevent such cost shifting.⁷ At the pre-hearing conference

⁵ The administrative record relating to these specific issues in Application (A.) 98-07-003 et al. was incorporated into this rulemaking. Judicial notice was also taken of specific information in the DWR Revenue Allocation Proceeding A.00-11-038 et al. (See Letter of January 25, 2002, to the parties that accompanied the Draft Decision of ALJ Barnett.)

⁶ D.02-04-067, pp. 4-5.

⁷ Proceedings to determine DA CRS were initiated by an ALJ ruling issued December 17, 2001 in A.98-07-003. By joint ruling on December 24, 2001, the

(PHC) held on February 22, 2002, certain parties advocated that cost responsibility should also include consideration of “Departing Load” customers. An administrative law judge (ALJ) ruling issued on March 29, 2002, prescribed that the scope of issues in this proceeding be expanded to include cost responsibility relating not only to DA, but also to DL.

In pleadings and testimony of parties in this proceeding, a variety of terms have been used to refer to the charges to be imposed pursuant to D.02-03-055. These terms have included expressions such as “nonbypassable charge,” forward or ongoing costs, and “exit fee.” For the sake of uniformity and clarity, and consistent with D.02-11-022, we shall use the term “cost responsibility surcharge” (CRS) as an umbrella term taking into account all of the various charge components at issue in this proceeding that are applied to Customer Generation load as discussed in this order.

Although the criteria and basis for determining the applicability of a CRS to Customer Generation is based on the record in this phase of the proceeding, the determination of specific cost elements relies upon certain methodologies set forth in D. 02-11-022 applicable to DA customers, in conjunction with companion proceedings in A.00-11-038 et al.

II. Procedural Summary

Parties filed prehearing opening briefs on April 22, 2002, and reply briefs on May 6, 2002 on legal issues relating to the Commission’s authority to impose cost responsibility charges both on DA and DL

issue of DA cost responsibility was transferred from A.98-07-003 to A.00-11-038 et al. Finally, D.02-04-052, issued on April 22, 2002, transferred consideration of cost responsibility issues from A. 00-11-038 et. al. to R.02-01-011.

customers. Opening testimony was mailed on June 6, 2002 and reply testimony was mailed on June 20, 2002, which addressed both DA and DL issues.

By ALJ bench ruling on the first day of hearings on DA issues, DL issues were bifurcated into a separate hearing phase. Parties accordingly submitted supplemental testimony on September 11, 2002 and supplemental reply testimony on September 23, 2002 relating to DL issues. Evidentiary hearings on DL issues began on October 7, 2002 and continued intermittently through October 18, 2002.

During the course of the hearings, various parties (i.e., Settling Parties) entered into settlement discussions on certain issues relevant to this phase. Pursuant to Rule 51.1 (b), on October 2, 2002, the Settling Parties issued a notice of settlement conference for October 9, 2002. A draft version of a Settlement Agreement was served on all parties on October 8, 2002. Subsequent to the settlement conference, all parties were given the opportunity to submit informal comments on the proposed settlement to the Settling Parties.

On October 17, 2002, a motion was filed for adoption of a Settlement Agreement sponsored jointly by a number of parties to the proceeding.⁸

⁸ The Joint Settling Parties include Arden Realty, Inc., Building Owners and Managers Association of California, California Energy Commission, California Independent Petroleum Association, Clarus Energy Partners, L.P., Cummins West, Inc., Energy Producers and Users Coalition (EPUC) [EPUC is an *ad hoc* coalition representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., Texaco Exploration and Production Inc., Equilon Enterprises LLC dba Shell Oil Products US, ExxonMobil Power and Gas Services Inc., on behalf of Exxon Mobil Corporation, THUMS Long Beach Company, Occidental Elk Hills, Inc., Tosco Corporation a Subsidiary of Phillips

Because the scope of the Settlement Agreement addressed only Customer Generation, but not municipal load issues, the proceeding was further bifurcated to provide for separate consideration of issues that were the subject of the Settlement Agreement apart from remaining contested issues relating to municipal load.

Comments on the Settlement Agreement were filed on October 31, 2002,⁹ and reply comments on November 6, 2002. In comments, various parties opposed certain provisions in the Settlement, and suggested alternative revisions. Only two parties, ORA and SDG&E, argued that the Settlement did not impose enough costs on Customer Generation load.

Petroleum Company, and Valero Refining Company – California], Goodrich Aerostructures Group, Hawthorne Power Systems, Hess Microgen, International Power Technology, Kern Oil and Refining Company, Kimberly Clark Corporation, next>edge, Inc., Nextek Power Systems, Inc., PG&E, Onsite Energy Corporation, Paramount Petroleum Corporation, RealEnergy, Inc., Silicon Valley Manufacturing Group, Edison, The Utility Reform Network (TURN), University of California/California State University, and USS-POSCO Industries.

⁹ The following parties submitted comments on the Settlement Agreement: Agricultural Energy Consumers Association (AECA), Alliance for Retail Energy Markets and the Western Power Trading Forum (AReM/WPTF), California Consumer Power and Conservation Financing Authority (CPA), California Large Energy Consumers Association (CLECA), California Solar Energy Industries Association (CalSEIA), Capstone Turbine Corporation, Ingersoll-Rand Energy Systems, Bowman Power Systems, CoGen Equipment Solutions, Inc., and Sempra Energy Connections (collectively, Capstone), Catholic Healthcare West (CHW), Center for Energy Efficiency and Renewable Technologies (CEERT), County of Los Angeles (LA County), County Sanitation Districts of Los Angeles (Districts), Eastside Power Authority (Eastside), Joint Settling Parties, Office of Ratepayer Advocates (ORA), SDG&E.

In addition, the South Coast Air Quality Management District (SCAQMD) submitted a letter to Commissioner Lynch dated October 30, 2002, and DWR filed reply comments on November 4, 2002, on the Settlement Agreement.

The remaining parties opposed to the Settlement argued that it imposed too many costs on Customer Generation load.

Post-hearing opening briefs were filed on November 7, 2002 and reply briefs on November 14, 2002. In view of the settlement, parties shortened or waived certain cross-examination. The underlying testimony of witnesses in this phase of the proceeding was received into evidence without objection. In the joint motion, Settling Parties argue that no evidentiary hearings are necessary prior to adoption of the Settlement Agreement in view of the evidentiary record already before the Commission. In comments in response to the motion, no party asked for evidentiary hearings on the merits of the Settlement Agreement.

Thus, as the basis for adjudicating issues in this phase of the proceeding, the record consists of (1) the evidence developed through written testimony and oral cross examination on the underlying merits of issues in dispute and (2) the Settlement Agreement.

III. Proposed Settlement

A. Summary of the Proposed Settlement

The proposed settlement agreement addresses issues relating to cost responsibility surcharges for DL served by onsite or “over-the-fence” generation. The settlement addresses DG issues only, but does not address cost responsibility for municipal load. Issues relating to municipal load will be addressed in a separate order.

The Settlement Agreement proposes that DL that began to receive service from onsite or over-the-fence generation after January 17, 2001, pay a “DWR Shortfall Charge” equal to 72 percent of the DWR bond charge

imposed on bundled service customers.¹⁰ “Existing” and “grandfathered” DL are exempt from paying any surcharge for DWR’s ongoing costs, as is DL served by new onsite or over-the-fence generation up to an annual megawatt (“MW”) cap.¹¹ DL covered by the Settlement Agreement is required, however, to continue to contribute toward the recovery of the HPC costs in SCE’s Procurement Related Obligation Account (PROACT)¹², SCE’s past procurement-related undercollections.¹³ Finally, the Settlement Agreement would require that DL that is not statutorily exempt from paying CTC to pay a tail CTC consisting of the components specified in Pub. Util. Code Section 367(a).¹⁴

The Settlement Agreement does not address certain issues that Settling Parties do not consider to be fully ripe for determination, such as the applicability of an HPC for PG&E, or how, if at all, generator refunds in pending FERC dockets would apply to DL customers. The Settlement Agreement likewise does not address narrow issues that Settling Parties believe are better left to case-specific applications. For example, specific questions relating to the implementation of charges at customer sites with multiple accounts, and sites at which the customer maintains no utility connection are not addressed in the Settlement. The Settlement Agreement also does not address the question of exception from CRS for “eligible

¹⁰ Settlement Agreement, Section 5.

¹¹ *Id.*, Section 6.

¹² See D.02-07-035 as modified by D.03-02-035

¹³ *Id.*, Section 7.

¹⁴ *Id.*, Section 8.

customer generators” as defined in Pub. Util. Code Section 2827(b)(2), or “eligible biogas digester customer-generator” as defined in Pub. Util. Code Section 2827.9.

Various parties filed comments opposing the Settlement. ORA and SDG&E oppose the “Shortfall” charge, and argue, instead, that a DL should pay full share of the DWR Bond Charge on the same pro rata basis that applies to bundled and DA customers. Additionally, ORA opposes the proposed exclusions from ongoing DWR power charges under a megawatts (MW) cap. Other parties representing CG interests opposed the Settlement for opposite reasons, arguing against imposition of any surcharges on the basis that it would be contrary to public policy and statutory mandates in favor of developing new sources of alternative generation.

B. Standard for Considering Settlements

In this phase of the proceeding, the record consists of (1) the evidence developed through written testimony and oral cross examination on the underlying merits of issues in dispute and (2) the Settlement Agreement which represents a negotiated compromise of certain parties.

The Settlement Agreement is sponsored by parties representing a range of interests, including bundled utility customers, customers who are in the process of developing Customer Generation to meet their electricity requirements or have already departed the utility grid, generation developers and turbine manufacturers, investor-owned utilities, and affected state agencies and educational institutions.¹⁵

¹⁵ Joint Settling Parties’ Comments, pp. 38–39.

The Settlement, however, is not supported by all parties. Certain provisions within it were also opposed by a number of parties, including ORA, SDG&E, and various parties representing Customer Generation interests.

In reviewing the Settlement, we are guided by the Commission's Settlement Rules set forth in the Rules of Practice and Procedure, Article 13.5: "Stipulations and Settlements." Rule 51.1(e) provides that the Commission must find a settlement, whether contested or uncontested, to be "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement. As we explained in D.96-01-011:

"[W]e consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law." (Re Southern California Edison Company [D.96-01-011] (1996), 64 Cal.P.U.C.2d 241, 267, citing Re Natural Gas Procurement and System Reliability Issues [D.94-04-088, p.8 (slip op.0)] (1994) 54 Cal.P.U.C.2d 337, 343)

In D. 01-12-018, we stated that when a contested settlement is presented to us where hearings have been held on the contested issues, we are free to consider such settlements under Rule 51.1(e) or as joint recommendations that may or may not be supported by the evidence in the record. In this instance, evidentiary hearings were held on the contested issues, although various parties elected to waive or curtail cross-examination. Nonetheless, the underlying testimony was received into

evidence, and forms an independent basis against which to evaluate the reasonableness of the Settlement Agreement.

Under Rule 51.1(e), we may reject a settlement if one or more of its elements are not consistent with our policy or the law, without elaborate examination of all the elements and without dealing with each contention of each party. We recognize that considerable time and effort has been expended preparing this settlement, which is sponsored by a number of parties representing diverse interests. Nevertheless, we cannot abandon our regulatory obligations in favor of a negotiated outcome.

In this instance, upon review, we find that the terms of the Settlement are not in the best interest of the public. While the Settlement reflects a broad range of divergent interests, including those of the utilities (i.e., PG&E and SCE), residential customers (i.e., TURN), commercial and industrial customers who have developed, or are developing, customer generation projects (i.e., BOMA, EPUC, and CIPA), developers of Customer Generation (i.e. Clarus Energy Corporation and Real Energy), the UC/CSU and the CEC, the Settlement is not supported by other parties (ORA, SDG&E) who raise important concerns with the overall settlement. Additionally, various specific provisions of the Settlement have been protested by CEERT, CalSEIA, and Capstone. As discussed further below, we find merit in the objections raised by ORA and SDG&E regarding Navigant's forecast of customer generation. We also find merit in CEERT's objections to the Settlement Agreement's treatment of clean/ultra-clean distributed generation.

C. Comments to the Settlement Agreement

In comments on the Settlement Agreement, a number of parties raised various concerns with specific provisions of the Settlement Agreement and ORA and SDG&E objected to the Settlement Agreement in its entirety. While AReM/WPTF neither opposes nor supports the Settlement, it notes its concern that in the absence of “straightforward and transparent rules” for administering the allocation of annual MW cap, smaller projects will face significant barriers in qualifying within the cap.

CLECA argues that while it may have made sense to impose CTC charges when utilities were receiving market prices for their output, now that that market structure is absent, it no longer makes sense for departing load to pay any portion of the CTC. Similarly, CMTA argues that Pub. Util. Code Section 372(a)4 exempts load served by cogeneration projects from the tail CTC.

CalSEIA argues that the Settlement Agreement fails to address provisions in the Public Utilities Code and Assembly Bill 58 (AB58), Stats. 2002, ch.836, that limit the Commission’s authority to impose surcharges on net metered customers.

Capstone does not support the Settlement Agreement because it is inconsistent with state policy aimed to promote clean distributed generation. Capstone argues that an exemption from departing load surcharges should apply to small, clean distributed generation that (1) is less than 5 MW, (2) is located within a single facility, (3) is on-site/over-the-fence load pursuant to Pub. Util. Code Sections 216 and 218, (4) is powered by fuel, other than diesel, and (5) complies with emission standards adopted by the State Air Resources Board.

ORA objects to the MW cap proposed by the settling parties. It argues that the basis for the MW cap is a forecast done by Navigant which has little, if any, connection to actual purchasing decisions by DWR.

CEERT reminds the Commission that Pub. Util. Code Section 353.2(b) allows the Commission to “consider energy efficiency and emission performance to encourage early compliance with air quality standards established by the State Air Resources Board for ultra-clean and low-emission distributed generation.”

D. The Settlement Agreement and the Public Interest

The majority of the parties support the settlement agreement. However, some parties raise serious objections to major underlying aspects of the settlement agreement. In evaluating the merits of the Settlement Agreement, we must find a balance between the public interest, the settlement agreement and the objections raised by the parties to provisions of the settlement agreement.

In looking at the public interest, we must first assure ourselves that each element of the settlement is consistent with the policy and intention established in this proceeding to prevent cost-shifting of DWR costs incurred on behalf of IOU customers and to establish a stable customer base.¹⁶ This settlement agreement has only one underlying element which we need to consider – the application of a statewide departing load cap of approximately 3000 MW to exempt new and additional Departing Load over the course of the next 9 years.

¹⁶ See D.01-09-060, p. 4 (slip op.); see also D.01-10-036, p. 23 (slip op.), modifying D.01-09-060.

Going forward, the settlement agreement proposes to exempt (1) “Grandfathered” DL that becomes operational on or before January 1, 2003, or that submitted its CEQA application on or before August 29, 2001, and becomes operational on or before January 1, 2004, and (2) “Qualifying” new DL that falls within an annual megawatt cap.¹⁷

The MW cap proposed in the Settlement Agreement is based on the forecast of Customer Generation that was available to DWR at the time the contracts were being negotiated. Settling Parties argue that there is therefore a logical connection between the amount of Customer Generation excluded from going-forward costs and the amount of Customer Generation for which DWR was not negotiating contracts. We do not agree. The cap relied upon in the settlement agreements simply represents Navigant’s forecast of possible customer generation. And while Navigant was providing DWR with forecasts which it used to negotiate long-term contracts, we find nothing in this record to suggest that there is indeed a logical connection between the amount of customer generation predicted by Navigant and the amount of load for which DWR did not procure long-term or short-term power. In fact, as ORA points out, during evidentiary hearings Navigant witness Mr. Macdonald noted that its “job was generally to give them [DWR] the facts and not to make recommendations in terms of how much they should be buying or the specific terms of the contracts.”¹⁸ The record simply does not support the

¹⁷ For ease of exposition, parties’ comments generally refer to “a cap” as if it was a single annual figure. In fact, the caps vary by year corresponding with Navigant’s forecasts.

¹⁸ Evidentiary Hearing Transcript, Volume 12, pp.1472:11-20

extent to which DWR's energy procurement efforts were affected by Navigant's forecasts. We acknowledge various parties' comments that Navigant was mandated to use the utilities' load forecasts to assist the Department of Water Resources in its short- and long-term power purchases. However, as evidenced by the long position of DWR power contracts during many time periods, DWR was purchasing power to keep the lights on. The forecasts prepared by Navigant were simply used as a point of reference rather than as absolute guides. Ultimately, we remain unconvinced that the record in this proceeding fully supports the connection between the forecasts of possible departing load and the DWR long-term procurement.

We are concerned that adopting a large cap would create further large undercollections and shifting of direct access costs to bundled customers. To put the amount of the proposed statewide cap into context, we note that in D.02-11-022, which imposed a cap on DA CRS, at issue was approximately 10,500 GWh annually of migrated direct access load.¹⁹ As proposed in the Settlement Agreement, the total statewide cap of 2,958 MW represents at least the same level of load on an annual basis. Table 1 below quantifies the annual GWhs as proposed by the Settlement Agreement assuming 100% and 50% load factors. We do not find that the level of statewide cap as proposed in the Settlement Agreement is in the best interest of bundled ratepayers.

¹⁹ As used in D.02-11-022, migrated direct access load is the difference the incremental direct access load that migrated to direct access between July 1 and September 20, 2001.

Table 1				
Year	Annual Statewide MW Cap	Cummulative Statewide MW Cap	GWh @ 100% LF	GWh @ 50% LF
2003	740	740	6,482	3,241
2004	294	1,034	9,058	4,529
2005	310	1,344	11,773	5,887
2006	269	1,613	14,130	7,065
2007	270	1,883	16,495	8,248
2008	268	2,151	18,843	9,421
2009	268	2,419	21,190	10,595
2010	268	2,687	23,538	11,769
2011	271	2,958	25,912	12,956

Further, adopting a broad statewide cap which exempts cogeneration, renewable technologies, or ANY other type of generation that is dedicated wholly or in part to serve a specific customer's load goes far beyond our intentions adopted in other proceedings to encourage renewable generation. As proposed in the Settlement Agreement, for the purpose of the DA CRS, the statewide cap treats renewable generation equal to non-renewable generation. We find this treatment not to be in the public's best interest nor consistent with the commission's previous positions to encourage renewable technologies. As we will explain further below, special treatment for clean/ultra-clean DG and net metered generation is consistent with the intent of the legislature and this commission to encourage renewable generation. Further, it provides for the proper incentives for renewable technologies that meet certain criteria

without subsidizing non-renewable technologies that happen to fall within the cap proposed by the Settlement Agreement.

According, we reject the settlement agreement.

IV. Treatment of Clean & Ultra-Clean DG and Net Metered Customers

A. Position of Parties Regarding Small Distributed Generation

A number of parties argue that the cap is unfair to smaller generators, and seek various exemptions from the cap based on public policy considerations.²⁰ AReM/WPTF, for example, recommends that new small cogeneration projects with a nameplate rating of five MW or less be exempt from the annual MW cap. AReM/WPTF express concern that the annual MW cap could be “eaten up” by a few large cogeneration projects and recommends that new small cogeneration projects with a nameplate rating of five MW or less be excluded from the annual megawatt cap.²¹ This concern is heightened by the provision of the Settlement Agreement that sets aside ten percent of the annual cap for one specific customer.²²

The CPA recommends that all small DG²³ projects of one MW or less in size be exempt from the need to qualify under the annual MW cap on

²⁰ See, e.g., Districts Comments; AReM/WPTF Comments; Capstone Comments; CPA Comments; CEERT Comments; CALSEIA Comments; SCAQMD Comments.

²¹ AReM/WPTF Comments, pp. 2–8.

²² AReM/WPTF Comments, Appendix A, ¶ 1.a.

²³ The terms “distributed generation,” “onsite and over-the-fence generation” and “self-generation” are used interchangeably.

departing load exempted from CRS for CDWR's ongoing costs, and, instead, should be automatically exempt from such charges.²⁴

CPA also recommends that zero, near-zero and low-emission ("ultra-clean") DG technologies be exempt from paying tail CTC and SCE's PROACT costs.²⁵ Similarly, the South Coast Air Quality Management District (District) seeks exemption for small "ultra-clean" DG of five MW or less in size from all cost responsibility surcharges.²⁶ The Center for Energy Efficiency and Renewable Technologies ("CEERT") also calls for the exemption of ultra-clean DG without regard to the MW cap,²⁷ as does Capstone Turbine Corporation ("Capstone").²⁸

CEERT argues that imposing CRS on emerging, ultra-clean distributed generation will impair the ability of these technologies to compete against dirtier, gas-fired forms of distributed generation, such as single-cycle microturbines and diesel generators.²⁹ CEERT claims that it would be contrary to legislative intent and state policy to apply excessive charges to DG producing zero, near zero, and low-emissions. CEERT argues that the Settlement Agreement will inappropriately penalize customers for choosing to operate zero, near-zero and low-emission DG.

²⁴ CPA Comments, filed Oct. 21, 2002, p. 1.

²⁵ CPA Comments, filed Oct. 21, 2002, p. 2.

²⁶ SCAQMD Comments, filed Oct. 31, 2002, p. 2.

²⁷ Exhibit (Ex.) 16, at p. 2 (CEERT (Starrs)). CEERT is a non-profit coalition of environmental and public interest groups, renewable energy providers, green energy marketers and energy efficiency technology companies founded in 1990.

²⁸ CEERT Comments, filed Oct. 31, 2002, pp. 4-6.

²⁹ Ex. 16, at p. 3 (CEERT (Starrs)).

CEERT proposes a three-tiered approach to encourage use of and achieve the greatest environmental benefit from zero, near-zero and low-emission DG: (1) a minimum of several hundred new MW of zero, near zero and low-emission distributed generation technologies should be brought on-line by 2005 (2) discounted fees should be applied to these technologies based on performance; and (3) net metered solar and biogas installations should be exempted from CRS entirely, primarily due to practical difficulties in implementation.

CEERT expresses concern that the CARB may be pressured to roll back recently adopted DG emissions standards unless a minimum of several hundred MWs of DG, which meet the 2007 standards, are installed by 2005.³⁰ CEERT, therefore, recommends that the Commission act to encourage the addition of as much on-line capacity as possible of zero, near-zero and low-emission DG by 2005. The structure for implementing this goal should include first-in-line priority to entering the system over other dirtier types of technologies, exempting these clean technologies from any potential future cap(s) on DG, and possibly also targeting MW goals and an annual ramp-up schedule.

According to AECA, eligible biogas digester customer-generators are exempt from departing load charges, and therefore no new or additional charges that would increase an eligible digester customer-generator's charges beyond those of other customers in the same rate class may be included.³¹ Similarly, CEERT argues that the Legislature, in

³⁰ Exhibit (Ex.) 116 (CEERT (Starrs)). See also, California Code of Regulations, Title 17(3)(1)(8), Article 3 (Distributed Generation Certification Program).

³¹ AECA Comments, p.1

passing Assembly Bill 2228 (AB 2228), Stats. 2002, ch. 845, “specifically considered and elected to exempt biogas (also known as biodigester) projects from any net metering or other charges for departing the system,” and that CRS should not be imposed on biogas generators “by this proceeding.”³²

The CalSEIA recommends a blanket exemption for DL served by distributed solar generation.³³ CalSEIA opposes any surcharges on customers investing in solar generation facilities beyond otherwise applicable rates for net power drawn from the grid.³⁴ CalSEIA argues that imposition of surcharges beyond those provided for in otherwise applicable tariffs for net power would erect new and potentially very significant barriers to further development of clean, renewable generation, and would be inconsistent with numerous policies and programs established by the Legislature, the CEC, and the Commission.

PG&E proposes that if exemptions were granted to a limited class of DL customers that install “super clean” and/or efficient DG units, such exemptions should be based upon an evaluation and policy conclusion that the benefits of encouraging these DG technologies outweighs the cost-shifting burden other customers will have to bear.

³² CEERT Comments, pp. 6-7

³³ CalSEIA Comments, Oct. 31, 2001.

³⁴ Exs. 117, 118, and 119 (California Solar Energy Industries Association (CalSEIA) (Starrs and Shugar).

B. Discussion

Pursuant to AB970, In D.01-03-073 we adopted 3 different levels of incentives to encourage and promote self-generation. D.02-09-051 modified the 3 incentive categories to include an incentive for microturbines and internal combustion engines operating on renewable fuel. We note that this decision does not modify or alter the incentives provided in D.01-03-073 as modified by D.02-09-051.

However, in D.01-03-073 we found merit in parties' concerns that some non-renewable self-generation systems are less efficient and more polluting than combined-cycle technologies without waste heat recovery.³⁵ In establishing the incentive mechanisms for distributed generation, we noted the lack of definition for super-clean technologies to assist us in establishing "differential incentives for renewable and super clean distributed generation resources."

Senate Bill No. 1038 (see Stats. 2002, Ch. 515) added Pub. Util. Code Section 353.2 which (a) defines "ultra-clean and low-emission distributed generation" as any electric generation technology that commences its initial operation between January 1, 2003, and December 31, 2005, and:

"produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60-percent system efficiency on a higher heating value."

³⁵ D.01-03-073, p. 25

Pub. Util. Code Section 353.2(b) states: “In establishing rates and fees, the [C]ommission may consider energy efficiency and emission performance to encourage early compliance with air quality standards established by the State Air Resources Board for ultra-clean and low-emission distributed generation.” As such, consistent with the our intent in D.01-03-073 to establish incentives for super clean distribution and the legislature's mandate to encourage early compliance with air quality standards, we therefore adopt an exception of 350 MW for clean and super-clean DG as defined in Pub. Util. Code Section 353.2 (a) from DA CRS. We find that this approach harmonizes the need to avoid shifting DWR charges with the legislature’s intent to encourage compliance with the State Air Resource Board by considering emissions and efficiency in establishing rates for clean and ultra-clean DG.

We select 350 MW, as an interim level, because it represents a cautious amount which minimizes the impact on the bundled customers while providing an adequate level of clean/super-clean DG development. We recognize that this level is not a firm level; we will consider refining the level as we determine necessary after further review and analysis is developed in a future proceeding.

We do not agree with PG&E that limited exceptions for clean/super clean distributed generation should be based upon an evaluation of societal benefits. While we recognize that no societal benefit numerical analysis has been performed in this proceeding, the Legislature has given clear and direct indications of its intent to encourage and promote ultra-clean and low-emission distributed generation development. In

considering granting an exception to clean/super clean and low emission distributed generation, we are guided by the intention of the Legislature.

We agree with CalSEIA that absent an exemption of the DA CRS for distributed solar generation, the policy intention of the Legislature to promote further development of clean, renewable generation could suffer a significant setback. For the reasons stated above, we find our limited exemptions to be consistent with the intent of the Legislature to promote ultra-clean generation and provide for differential treatment for generation which meets the definition outlined in Pub. Util. Code Section 353.2.

AB 58 amended Section 2827.7 and exempts generation eligible for net metering that has permits on or before December 31, 2002, and is constructed on or before September 30, 2003 from any new or additional surcharges for the life of the system. Additionally, we also agree that the legislature specifically considered and elected to exempt biodigester projects from any net metering or other charges for departing the utility system. Accordingly, to comply with Pub. Util. Code Section 2827, eligible net-metered projects, including biodigester, should be exempt from all components of the CRS adopted in this order.

We recognize that not all customer generation that is eligible for net-metering may actually be net metered. Various parties raised concerns that providing an exception to net metered customer generation could potentially create a perverse incentive for some customers which would not necessarily choose to seek net-metered status do so simply to avoid paying any DA CRS charges. We believe that customer generation which would normally qualify for net metered status but rather chooses not to should be treated similarly as net metered customer generation. We

believe that by not imposing DA CRS on customers that meet clean/ultra-clean eligibility pursuant to Pub. Util. Code Section 353.2 and net metered eligible customers as defined in Pub. Util. Code Section 2827, we avoid the perverse incentive concerns of parties. A customer can qualify to avoid paying DA CRS by meeting either of these two requirements. As such, if a solar project chooses not become net-metered for any reason, it would still qualify under the cap offered to customers that are defined by Pub. Util. Code Section 353.2.

Parties argued that Pub. Util. Code Section 2827 (l) requires the Commission to impose DWR costs on net metered customers. They claim that our exception for net metering would be in violation of this statute. We disagree. Pub. Util. Code Sections 2827(k) and 2827 (l) both require that net metered customers pay “nonbypassable” fees, including bond charges, DWR power charges, and public purpose charges. By definition, a net metered customer does not bypass any charges since they continue to pay for these charges on their net energy consumption. Our interpretation in this decision with respect to treatment of net metered customers is consistent with the provision of Pub. Util. Code Sections 2827(k) and 2827(l).

V. Legal Authority for Imposing Cost Responsibility Surcharges

Any charges we impose in this decision must be consistent with the law. Various parties representing departing load interests generally argue that the Commission lacks jurisdiction over the right to engage in Customer Generation and the charges associated with it. EPUC/KCC/GAG also claimed that such charges are prohibited by law and contrary to principles of cost causation. Various parties also claimed

that explicit state and federal policies encouraging the development of Customer Generation would be frustrated by the imposition of any CRS on DG load.

We conclude that the Commission has the requisite legal authority to authorize and implement cost responsibility surcharges on Customer Generation load. This authority is clearly set forth in Assembly Bill No. 117 (AB 117), which clarified the Legislature's intent concerning the implementation of AB 1X, and the recovery of DWR-related costs from retail end-use customers. (AB 117, Stats. 2002, ch. 838)³⁶ AB 117, which was signed into law September 24, 2002, the Legislature enacted Public Utilities Code Section 366.2(d)(1) which makes all end-use customers who took bundled service on or after February 1, 2001, responsible for a fair share of the costs incurred by DWR. This statutory provision provides:

“It is the intent of the Legislature that each retail end-use customer that has purchased power from an electric corporation on or after February 1, 2001, should bear a fair share of the [DWR's] electricity purchase costs, as well as electricity purchase contract obligations incurred... that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.” (Pub.Util. Code, Section 366.2, subd. (d)(1).)

³⁶ The Commission's authority to adopt and allocate CRS to Customer Generation load is also found in AB 1X concerning the obligations of retail end-use customers for DWR costs, and our broad authority to regulate “...to do all things...which are necessary and convenient in the exercise of such power and jurisdiction,” under Public Utilities Code Section 701. (See discussion, D.02-11-022, pp. 11-13 (slip op.))

Thus, AB 117 gives the Commission the authority for imposing a “fair share” of cost responsibility on customers, including Customer Generation Departing Load that took utility service on or after February 1, 2001. The determination of what the “fair share” should be is left to the Commission’s determination in its exercise of this authority.

However, in addressing the energy problems confronting California which resulted in enactment of AB 1X, the Legislature also enacted several laws with the legislative objectives to promote investment and construction of renewable energy resources, diversify California’s energy resource mix, stabilize California energy supply infrastructure and produce economic and environmental benefits. (See generally, Assembly Bill No. 29 (“AB 29”), Stats. 2001, Ch. 8, enacting Public Utilities Code Sections 2827, 2727.4 and 2827.7 (net energy metering for eligible customer generation); SB 28X, Stats. 2001, Ch. 12, enacting Public Utilities Code Section 353.1, et seq. (distributed energy resources); Senate Bill No. 1038 (“SB 1038”), Stats. 2002, Ch. 515, adding Public Utilities Code Section 353.2 and amended Public Utilities Code Section 383.5 (increasing the amount of renewable electricity generated in California); AB 58, Stats. 2002, Ch. 836, amending Public Utilities Code Sections 2827 and 2827.7, and added Section 2827.8 (operation and development of emerging renewable resource technologies and net energy metering); AB 2228, Stats. 2002, Ch. 845, enacting Public Utilities Code Section 2827.9 (net energy metering for eligible biogas digester customer generation).)³⁷

³⁷ AB29 was signed into law on April 11, 2001 and SB 28X was signed into law on May 22, 2001. AB 1038 became law on September 12, 2002. The Governor signed AB 58 and AB2228 into law on September 24, 2002. This is the same date that AB 117 was signed into law.

In implementing AB117, we are cognizant that our implementation should not be in conflict with other statutes, including the legislative intent codified in these statutes, enacted at the same time and in response to the electricity problems confronting California. It is important that the Commission's determinations regarding its implementation of AB 117 should be in harmony with those other statutes the Legislature enacted in response to problems confronting California. Thus, our interpretation in today's decision reflects our harmonizing of the AB 117 and these statutes.³⁸ Accordingly, we have provided for CRS exceptions as specified in today's decision.

For example, Public Utilities Code Section 353.2 provides:

"In establishing rates and fees, the commission may consider energy efficiency and emissions performance to encourage early compliance with air quality standards established by State Air Resources for ultra-clean and low-emission distributed generation." (Pub. Util. Code Section 353.2, subd. (b).)

Thus, despite apparent contrary language in AB 117, we have harmonized Pub. Util. Code Sections 366.2(d) with Pub. Util. Code Section

³⁸ When confronted with an apparent conflict between statutes, the rules of statutory construction requires that the statutes be harmonized so as to give effect to such statutes insofar as possible. (See e.g., *Waters v. Pacific Telephone Company* (1974) 12 Cal.3rd 1, 11; *Rubin v. Green* (1993) 4 Cal. 4th 1187, 1201; *San Diego Gas & Electric v. Carlsbad* (1998) 64 Cal. App. 4th 785, 793.) the interpretations of the statutes should also be guided by consideration of the statutes in context of the statutory framework, including when the statute was enacted and for what public purpose. (See e.g., *Neumarkel v. Allard* (1985) 163 Cal. App. 3rd 457, 461-462; see also, *Moyer v. Workmen's Compensation Appeals Board* (1973) 10 Cal. 3rd 222, 230)

353.2(b) to permit an exception for the payment of CRS for load involving ultra-clean and low-emission distributed generation.

VI. Prevention of Cost Shifting

The Commission's policy on prevention of cost shifting has been previously set forth in D.02-03-055. Although this policy was articulated in the context of the suspension of DA load, the concern also is relevant to DL. Nonetheless, there are differences between DA and DL customer bases that are relevant in considering the effects of cost shifting. The cost shifting concerns relating to DA load, as articulated in D.02-03-055, focus on maintaining bundled customer indifference resulting from whether DA was suspended on September 20, 2001 as opposed to July 1, 2001. Between these two dates, there was significant migration from bundled to DA load. DWR did not incorporate this significant migration from bundled to DA load in its long term contracting for power during early 2001, but incurred a significant level of costs on behalf of customers that subsequently switched to DA. A cost responsibility surcharge was thus required to avoid shifting those costs incurred on behalf of DA load onto bundled customers. The question of cost shifting, therefore relates to whether or to what extent, DWR incorporated a particular segment of load into its procurement of power for bundled customers.

The circumstances giving rise to DA cost shifting, however, do not apply in the same manner to DL served by Customer Generation. In contrast to DA, for example, there has been no suspension of DL, nor any marked increase in migration to DL during the period between July 1 and September 20, 2001. Instead, the departure of load to sources served by Customer Generation has been going on for a number of years.

However, as we have articulated in D.02-11-022 the legal basis for establishing a DACRS on customers. We stated:

Further, under Pub. Util. Code Section 701, the Commission has broad authority to regulate and to “do all things...which are necessary and convenient in the exercise of such power and jurisdiction.” Moreover, as a general matter and consistent with the law, the charges or rates imposed by this Commission must be “just and reasonable” and must not be unfairly discriminatory. (See Pub. Util. Code Section 451 and 453.) In accordance with these statutory requirements, bundled customers may not be arbitrarily charged for obligations which rightfully are the responsibility of DA customers.

Further, in the discussion above on our denial for the settlement agreement, we have explained our concerns with the use of the forecast of customer generation by Navigant. We cannot conclude that the cap proposed in the Settlement represents a reasonable approximation of the level of Customer Generation demand assumed by DWR in forecasts underlying its procurement of contract power.

VII. Overview of Parties’ Positions

In their pre-settlement cases-in-chief, parties generally gravitated into one of two groups. There were also certain variations of parties’ positions within a group.

One group, generally representing the views of bundled customers and utility interests was composed of the utilities, ORA, and TURN. Within this group, PG&E, SCE, ORA, and TURN all argued that DL that departed the utility system after January 17, 2001, should bear a share of

both past and future costs on an essentially similar basis to their respective proposals for DA customers. SCE sought to recover an HPC element from customers that became DL after March 29, 2002, the date of the ALJ ruling formally notifying DL customers that such charges were being considered in this proceeding.

SDG&E proposed that DWR Bond Charges be recovered from all customers, including all forms of DL that remain directly or indirectly connected to the grid. SDG&E proposed, however, that DL served by customer self-generation generally be excluded from paying for DWR ongoing power charges, based on the premise that DWR did not incur costs to serve this load. SDG&E is already recovering a competition transition cost (CTC) component from DL customers under its existing tariffs, and proposes no change in that process. SDG&E argues that a surcharge should apply only to DL that was not anticipated by DWR when it made purchases and for which it incurred costs that became stranded.

The other major group of parties generally comprised interests representing various aspects of the Customer Generation market. In their pre-settlement testimony, these parties generally opposed imposition of any surcharges on DL customers, citing legal, factual, and policy reasons. Parties cite state and federal statutes, including AB 1890, AB 1X, Pub. Util. Code Sections 216 and 281, and the Public Utilities Regulatory Policies Act (PURPA) to support their claims. Parties argue that Customer Generation projects are more appropriately characterized as demand reduction or energy efficiency measures that provide quantifiable benefits to customers and the state's energy grid.

Certain parties, including EPUC/KCC/GAG, UC/CSU, AREM, and CalSEIA, argued that the Commission lacked legal authority and a policy basis upon which to impose these charges retroactively. EPUC et al argue that Pub. Util. Code Section 218(a) and (b) place customer-owned generation outside the scope of this Commission's jurisdiction, and that it is subject only to FERC regulation pursuant to PURPA. These parties argue that no legislation gives the Commission the authority to impose a surcharge for DWR costs or costs for purchased power from qualifying facilities (QFs) and utilities' retained generation. To the extent that the Commission retains any right to regulate customer generation, they claim that it is limited to the development of standby service rates.

These parties contrast the Legislature's decision to authorize the suspension of new direct access contracts (Water Code Section 80110), with the Legislature's strong support for the construction of new generation, particularly cogeneration and distributed generation. These parties cite legislation such as AB 970 and SB 28X as intending to encourage private investment in new generating facilities in order to relieve the strain upon the state's system.³⁹ Given the recent cancellations and delays in the planned construction of large power plants in the state, they argue that the need for small generation facilities is even more critical.

Parties further argue that Customer Generation did not cause DWR to incur costs, and accordingly, such generation should not be subject to surcharges.

³⁹ (See D.01-06-035, p. 1 ("given the current electricity crisis facing California, it is important to bring new generation capacity on-line this year"))

VIII. Review of Charges to be Imposed on Departing Load Customers

A. Recovery of DWR Bond Charges

1. Background

Current bundled customers, like DL customers who received bundled service subsequent to January 17, 2001, did not pay fully for the DWR's procurement costs incurred during 2001. In order to reduce the immediate impact, DWR anticipated financing a part of the costs incurred during 2001 at the highest levels by issuing bonds. Under AB 1X, the revenue shortfall for the historic period was to be financed through the sale of State of California Bonds. In D.02-02-051, the Commission adopted a "Rate Agreement" governing the terms by which the Bonds would be administered. As stated in D.02-02-051:

Under the Act, the Commission has an obligation to impose charges on electric customers that are sufficient to compensate DWR for its costs under the Act, including procuring and delivering power, and paying bond principal and interest.

The adopted Rate Agreement establishes two streams of revenues. One stream of revenues will come from Bond Charges imposed on electric customers, and is designed to pay for bond-related costs. The second stream of revenues will come from Power Charges imposed on electric customers who buy power from DWR, and is designed to pay for the costs that DWR incurs to procure and deliver power. Both streams of revenue are necessary for DWR to issue bonds with investment-grade ratings.

In D.02-11-022, we directed that a Bond Charge be imposed on DA customers (other than those that have remained continuously on DA

service) on a cents/kilowatts-hour (kWh) basis equivalent to that imposed on bundled customers. The actual determination of the revenue requirement and per-customer bond charge, however, was to be implemented in A.00-11-038 et al. (the “Bond Charge” phase).⁴⁰ On October 24, 2002, D. 02-10-063 was issued, adopting a methodology for developing a DWR Bond Charges.

D. 02-10-063 was further amended on rehearing by D. 02-11-074. As explained in that order, DWR was to file by November 8, 2002, its more precise 2003 bond revenue requirement for bond-related costs with the Energy Division once the bonds have been placed and DWR has determined its actual bond-related charges. The utilities were to make compliance advice letter filings within 5 days following DWR’s updated submission to impose a per kWh hour Bond charge on non-exempt bundled consumption delivered on and after November 15, 2002. SDGE, SCE, and PG&E were to calculate a uniform per kWh charge by dividing the more precise 2003 bond revenue requirement by 106,222 GWh.⁴¹

The determination of whether, or to what extent, Customer Generation load should pay for Bond-related costs was deferred to the instant proceeding. Pending the implementation of any actual Bond Charge recovery, we made provision in D.02-10-063 for the tracking of

⁴⁰ The Rate Agreement provides that the Commission may impose Bond Charges on DA customers only after (1) the Commission issues an order that provides for such charges, and (2) the order becomes final and unappealable. See Rate Agreement, Section 4.3, as attached to D.02-02-051.

⁴¹ The load figure represents total forecasted load minus excluded residential, DA, and DL.

both DA and DL cost responsibility, and ordered each of the utilities to create a Bond-Charge Balancing Account (BCBA) for that purpose.

Once the instant decision addressing the applicability of Bond Charges to DL customers becomes final and unappealable, the actual Bond Charge component of the CRS will be implemented for Customer Generation load, on the terms as set forth in this order, as discussed below.

2. Parties' Positions Prior to the Settlement

Prior to the settlement, two opposing views generally emerged concerning applicability of the Bond Charge. Parties representing utility and bundled customer interests (i.e., ORA and TURN) contended that DL should pay all charges related to the DWR bonds on the same basis as bundled customers.⁴² Other parties proposed alternatives to a one-size-fits-all bond charge.⁴³

Parties representing Customer Generation interests advocated an opposing view. A number of parties claimed the Commission lacks authority to impose any charge related to the DWR bonds on DL.⁴⁴ Parties

⁴² See PG&E Bond Charge Allocation Phase in Rate Stabilization Plan Opening Testimony, Ex. 90, at 4-1 to 4-4; *see also* SCE Proposal for DL Non-Bypassable Charges (Exit Fees), Ex. 76 at 4-7; *see also* Rebuttal Testimony of SCE on Proposals for DL Non-Bypassable Charges (Exit Fees), Ex. 77 at 1-15.

⁴³ See Proposed Supplemental Testimony of Scott Tomashefsky on Behalf of the California Energy Commission, Ex. 123 at 3-7; *see also* A.00-11-038 Prepared Direct Testimony of James A. Ross on Behalf of the Energy Producers and Users Coalition and Others, Ex. 600, at 5, Schedule 3; *see also* A.00-11-038 Ex. 3.

⁴⁴ See Initial Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group on the Commission's Legal Authority to Impose DL Surcharges and Exit Fees at (EPUC/KCC/GAG Initial Brief) at 16-19, 25-29; *see also* Reply Testimony of Maric Munn and Mark Gutheinz on Behalf of the University of California and California State

also argued that imposing Bond Charges would run counter to various state and federal mandates to encourage the development of preferred forms of alternative generation, and that exceptions from payment of DWR's past cost should be made for small clean distributed generation,⁴⁵ for distributed solar generation,⁴⁶ and for certain other types of customer generation.⁴⁷

3. Discussion

The application of a uniform bond charge to Customer Generation load is consistent with D.02-02-051 in which the principles for application of the Bond Charge were articulated. In that order, we stated:

“The Act does not require Bond-Related Costs to be recovered through charges that are imposed only on the power that is sold by DWR. Nor does the Act require the use of a particular ratemaking method to recover DWR's Bond-Related Costs or Department Costs. Therefore, the Commission may use its broad authority under Water Code Section 80110 and Pub. Util. Code Section 451 and Section 701 to devise and implement the separate Power Charges and Bond Charges set forth in the Rate Agreement.

“At the time the Act was passed into law, it was unknown how the energy crisis would unfold or how

University Relating to Cost Responsibility for Direct Access and Departing Load Customers, Ex. 126, at 9-13; see also Reply Testimony of Steven A. Greenberg on Behalf of RealEnergy, Inc. and Joint Parties Interested in Distributed Generation/Distributed Energy Resources, Ex. 82 at 4-7.

⁴⁵ Capstone Comments, pp. 6-7.

⁴⁶ CalSEIA Comments, pp. 11-24.

⁴⁷ Districts Comments, p. 10.

long DWR might be selling power, which suggests that the Legislature intended to provide DWR and the Commission with great flexibility in the Act to devise a means to recover DWR's revenue requirement. . . . " (D.02-2-051)

On the other hand, the recovery methodology proposed in the Settlement differs from the approach that we have adopted for applying Bond Charges to bundled and DA customers. Instead of paying a full pro rata share of the full bond charge, Customer Generation load would only pay 72% of the requirements otherwise assessed against bundled and DA load.

The Shortfall Charge covers the administrative, financing, and reserve costs associated only with the historic undercollection, but the remaining reserve and deposit accounts making up the total bond proceeds. Settling Parties argue that to compensate for the upfront discount, Customer Generation would not receive the future benefit from the funds in those reserve accounts to the extent they are used to reduce future power charges or to shorten the term of the Bond Charge. Settling Parties argue that the lower upfront charge is merely an alternative rate design in comparison to that applied to bundled and DA load. Settling Parties portray the proposed treatment merely as a difference in the timing of charges, rather than as any absolute advantage over time.

Except as provided herein, we find this justification unconvincing. Further, as we have declined to adopt the proposed settlement agreement, we find that all departing load customers shall pay 100% of the bond charge.

As noted by SDG&E, it is not clear to what extent the bond reserves would be released at some future date to pay down the Bond obligation or to reduce future ongoing power charges. Reference Exhibit 1a in the Bond Charge Proceeding described what will happen to a large portion of these funds. The majority of the initial deposit to the Operating Account consists of an \$850 million increase to the Minimum Operating Expense Available Balance. This additional cushion in the Operating Account is only required so long as DWR continues to procure the Residual Net Short. As soon as that responsibility has been transferred to the investor-owned utilities, the Minimum Operating Expense Available Balance requirement will be reduced by \$850 million (even if DWR continues to be responsible for long term contracts). At that time, the freed up funds can be used to “either retire the additional debt issued to fund the higher account balance or can be used for more immediate ratepayer relief. The Commission, after consultation with the Department, will be responsible for determining the use of the excess amounts.⁴⁸” If the funds are used to retire debt, all customers responsible for paying Bond Charges will benefit. If the funds are used for more immediate ratepayer relief, the extent to which customers may benefit will depend on whether that relief comes in the form of a reduction to Bond Charges or Power Charges, or both, an issue that has not yet been decided.

Moreover, the Operating Reserve referenced in Exhibit 106 of the Bond Charge Proceeding is set aside to cover the contingency that the Operating Account may not be sufficient to fund all operating costs.

⁴⁸ Reference Exhibit 1a in the Bond Charge Proceeding A.00-11-038 et. al.

Absent this contingency, there is no certainty that the sums in the Operating Reserve Account will ever be used to fund DWR's ongoing power purchases. To the extent that these reserves do not become available to reduce future Bond or Power Charges, the purported benefit associated with Customer Generation waiver of any right to the future benefits of any reserves becomes illusory. Given the uncertainty as to how or to what extent current reserves may reduce charges, there is no assurance that bundled customers would ever see offsetting benefits in relation to the upfront benefit accorded Customer Generation through the 28% discount. Customer Generation could thereby gain an unfair advantage in relation bundled customers if they were granted a front-loaded 28% discount excluding these reserves.

Moreover, we disagree that the funding of reserve accounts for ongoing costs represents any improper "commingling" with historic shortfall costs. In D.02-11-022, we previously explained how the reserve accounts relate to the overall DWR Bond financing requirements. As stated by DWR in Exhibit 3, the hypothetical \$8.6 million bond issue "does not reflect the financing of any of the Department's power purchasing program reserves, the funding of which will be a condition of the rating agencies in order to secure the Department's desired level of investment grade ratings on the bonds."

Thus, the funding of the various operating reserves at closing is a pre-requisite to actually issuing the bonds. The rating agencies insisted on the setting aside of such large sums in these accounts in order to give the bonds favorable credit ratings. Without these large set-asides, the bonds would have had lower ratings, or perhaps could not have been issued at

all. An investment grade rating on the DWR Bonds is required by Water Code Section 80130. Lower ratings would have increased the interest on these bonds thus increasing their cost to DA customers. In short, customers receive a substantial benefit from these set-asides as they will enable the bonds to be issued with favorable ratings, thereby lowering interest charges. Thus, the cost of funding these set-asides form an integral part of the favorable financing terms applicable to the historic shortfall. By excluding the funding of these reserve accounts in the derivation of the 72% ratio, the Shortfall Charge does not account for any of the benefits realized by all affected customers, including Customer Generation, derived from the reserve accounts.

Moreover, as noted by SDG&E, assuming the reserve funds were used to retire the bonds early, the Settlement fails to explain what regulatory treatment would be applied to revenues collected from Customer Generation thereafter, or how the applicable shortfall charge would be determined when there is no remaining Bond Charge in place from which a 72% ratio can be applied.

Because we have found the bond charge to be an integrated whole, it would be improper and unfair to approve any discounted Shortfall charge that assumes such reserves can be severed. We find that this distinction is not supported by the record, nor is it consistent with the approach applied to DA customers in D. 02-11-022. Thus, we find persuasive the arguments presented by ORA and SDG&E that the Settlement does not meet the criteria for approval to the extent that it would impose a discounted Shortfall charge.

We likewise find no basis in the record of this proceeding to apply a 28% discount to DL customers on the basis of legislative mandates to promote development of various forms of alternative generation. As we noted previously, while we acknowledge that the record is lacking to quantify societal benefits for customer generation, there is a strong basis in Legislative intent, and the statutes codifying such intent, to differentiate between departing load and super-clean & low-emission distributed generation.

We find no basis here, however, to conclude that any potential benefits to be realized from deployment of Customer Generation necessarily relate in monetary terms to the 28% discount that would result from approving the Settlement's Shortfall Charge. We therefore cannot conclude that the Settlement is reasonable in light of the whole record in assigning a 28% discount to the otherwise applicable bond charge assigned to Customer Generation.

As noted by SCE witness Collette, specific issues relating to any valuation system that could be employed to assign value for the benefits that Customer Generation allegedly confers is pending before the Commission as part of R.99-10-025 (Rulemaking regarding Distributed Generation). The determination of incentives or subsidies, if any, that should apply for deployment and development of certain Customer Generation technologies is more appropriately addressed in the R.99-10-025 proceeding.

Based on the record in this proceeding, however, we find no basis to conclude that the Settlement is reasonable in applying a 28% discount off the Bond Charge reasonably reflects the dollar value of those benefits.

Possible adoption of subsidies to encourage deployment or to recognize benefits from preferred alternative generation technologies may be addressed further in R.99-10-025.

Except as discussed herein, we thus conclude that based on the record, Customer Generation should bear responsibility for the full Bond Charge, including associated reserve accounts, on the same basis as bundled and DA customers. This will ensure that there is no cost-shifting between different customers.

B. DWR Ongoing Power Costs

1. Positions of Parties Prior to the Settlement

In its case in chief, PG&E and SCE proposed that Customer Generation loads that departed from utility service after January 17, 2001, when DWR entered the procurement market on behalf of utility customers, should not be allowed to escape their fair share of DWR's ongoing power costs. PG&E argues that all customers on PG&E's system, as of January 17, 2001, benefited from DWR's role as "default provider." PG&E and SCE do not propose to apply any DWR charges to customers that departed its system prior to January 17, 2001, since such customers never benefited from DWR-procured power.

SDG&E does not propose to charge any Customer Generation load for DWR-related ongoing power charges. SDG&E does not believe that assessing such charges on such customers is warranted, arguing that DWR did not incur costs on behalf of such customers, but assumed they would procure their power independently of DWR through self-generation.

TURN proposed that Customer Generation should pay for ongoing DWR power charges, with the exception of eligible for standby charge

exemptions (net metered customers plus new Customer Generation under five MW installed before the specific dates established by legislation). TURN believes that this limited exemption would avoid double counting of charges that are already collected in those standby charges.

ORA proposes that all Customer Generation load should bear a share of the ongoing DWR power charge. ORA recommends, for now, adoption of an identical surcharge applicable both to direct access and departing load based on Navigant's modeling of the cost-impact of last year's return of a substantial load from bundled service to direct access. Any surcharge true up in 2003 or 2004 could then capture incremental cost impacts of departing load. ORA anticipates the three IOU's will actually implement a surcharge related to departing load via existing tariffs.⁴⁹

We agree with PG&E that customers taking bundled service as of January 17, 2001, benefited from DWR's role as "default provider" and should not avoid paying their fair share of ongoing DWR power costs.

We agree with TURN that, except for customers eligible for standby charges (net metered customers plus new Customer Generation under five MW installed before the specific dates established by legislation), departing load customers should pay for ongoing DWR power costs.

As we explained above in Section IV, we will not impose CRS on 350 MW of super-clean distributed generation as defined in Pub. Util. Code Section 353.2 (a) from the ongoing DWR power costs.

⁴⁹ For example PG&E Schedule E-Depart.

C. Tail CTCs

1. Background

The Settlement Agreement also addresses the recovery of certain utility-related above-market generation charges, commonly referred to as “tail” CTC applicable to DL served by Customer Generation. .” CTC was originally envisioned as a byproduct of a industry restructuring program to provide for a competitive environment pursuant to legislative enacted in AB 1890. As originally envisioned, AB 1890 was to provide for an “orderly” transition to a competitive generation market which would be completed by March 2002. (Pub. Util. Code Section 330.)⁵⁰

Pub. Util. Code Section 369 provides that “[t]he commission shall establish an effective mechanism that ensures recovery of transition costs referred to in Sections 367, 368, 375, 376, and subject to the conditions in Sections 371 and 374, inclusive, from all existing and future consumers in the [utility's] service territory . . . (Pub. Util. Code Section 369) Pub. Util. Code Section 368(a) prescribed that electric rates would remain fixed at the June 10, 1996 levels, except for residential and small commercial customer rates which were reduced by 10%. (Pub. Util. Code Section 368 subd. (a).) These frozen rates, along with a residual component of rates specifically delineated as the CTC, allowed the utilities to accrue the revenues to collect “transition costs.”

D.00-06-034 in the Post-Transition Period Ratemaking Proceeding (A.99-01-016) adopted a methodology for allocating ongoing transition costs after the end of the AB 1890 rate freeze, but did not address how such

⁵⁰ Except as otherwise indicated, all further statutory references are to the Public Utilities Code.

amounts were to be calculated. The decision directed PG&E to implement CTC through its Phase 2 general rate case (A.99-03-014) and SCE through A.00-01-009. Since these two proceedings have been suspended or otherwise terminated,⁵¹ the determination of ongoing CTC applicable to DL customers remains to be addressed in this proceeding.

2. Parties' Positions – Pre-Settlement

Certain parties opposed any charge to DL customers for ongoing above-market utility portfolio costs.⁵² Various parties representing Customer Generation interests argue that while AB 1890 gave the Commission limited authority to impose certain surcharges on direct access customers, it specifically exempted onsite customer generation from these charges. (Pub. Util. Code Section 372.) In addition, even where AB 1890 gave the Commission authority to impose surcharges, they claim that most were subject to a statutory sunset date of December 31, 2001.

CLECA argues that “it does not make sense” that utility tail CTC should continue to apply to departing load, on the premise that “the entire concept of tail CTC has lost any meaning in the wake of the Legislature’s

⁵¹ We note that on-going CTC issues will be considered in A.00-11-038 et al. Our consideration and determination of DL cost responsibility for going CTC in this order does not constitute any prejudgment of these issues. Also, depending on the outcome of those proceedings, our determinations with respect to DL customers and their cost responsibility for on-going CTC costs may be subject to adjustment.

⁵² *See, e.g.*, Supplemental Opening Testimony of Maric Munn and Mark Gutheinz on Behalf of the University of California and California State University Relating to Cost Responsibility for DL Customers, Ex. 125, at 9-10; Reply Testimony of Steven A. Greenberg on Behalf of RealEnergy, Inc. and Joint Parties Interested in Distributed Generation/Distributed Energy Resources, Ex. 83, at 9-11.

passage of AB 6X and the return to cost-of-service ratemaking for utility generation.”⁵³ Other parties argued in favor of similar exemptions from “tail” CTCs.⁵⁴

The utilities proposed, in contrast, that some measure of ongoing utility portfolio costs be imposed on DL.⁵⁵ PG&E proposed the continuation of the “tail CTC” under AB 1890.⁵⁶ SCE proposed that the Commission “establish a nonbypassable charge to recover the above-market costs of SCE’s portfolio of retained generation and energy contracts.” Unlike the “tail CTC” in AB 1890, SCE’s proposed measure would have been unlimited both in term and in the resources that could be included in the ongoing charge. SCE argues that the “tail CTC”, a more limited measure of ongoing utility portfolio costs, combined with a continuing cogeneration exemption, represents a reasonable compromise of positions in the interests of bundled ratepayers, the utilities and DL customers. SDG&E is uniquely situated with respect to its recovery of CTC because it has ended its rate freeze. SDG&E argues that the Commission, in this proceeding, should expressly authorize the continued collection of SDG&E’s CTC pursuant to existing tariff.

⁵³ CLECA Comments, p. 5.

⁵⁴ See CPA Comments, p. 2; Capstone Comments, p. 7; CEERT Comments, p. 5; CMTA Comments, p. 2; Eastside Comments, p. 2.

⁵⁵ See, e.g., SCE Proposal for DL Non-Bypassable Charges (Exit Fees), Ex. 76, at 15.

⁵⁶ See PG&E Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to AB 1X and Decision 01-09-060 Prepared Testimony, Ex. 87 (PG&E/Keane, Opening Testimony) at 2-3 to 2-7.

3. Discussion

Although parties disagree in principle over the interpretation of AB 1890, under which the concept of “tail CTC” originated, and its implications for DL cost responsibility, the Settlement represents a reasonable disposition of their differences. We conclude that the Settlement’s proposed imposition of tail CTC on Customer Generation load assigns them a fair share of costs, and is reasonable in light of Commission policy and applicable law. We have previously addressed the applicability of tail CTC to DA customers in D.02-11-022. Consistent with that order, we conclude that legal authority exists for imposing a share of above-market CTC-related costs on Customer Generation load.

We recognize that the concept of “transition costs,” as originally contemplated in AB 1890 no longer retains its initial meaning. When the Commission addressed “tail” CTC in its second Post Transition Ratemaking (PTR) order D.00-06-034, it envisioned a largely unregulated generation market after the end of the rate freeze. Section 367 envisioned that the utilities would sell their generating assets or market value them by the end of the AB 1890 transition period, and the only remaining utility retained generator (URG) that would not be subject to competitive market mechanisms would be QFs and other long-term power purchase contracts. Because utilities would be at risk in the market for recovery of their generation costs, it was important that they have assurance of recovery of these identified costs through an ongoing CTC charge.

After the extreme escalation in wholesale prices beginning in Summer 2000, however, it became apparent that California’s transition to electricity deregulation was not working. The Legislature enacted

emergency measures early in 2001 to deal with the energy crisis. Among these measures was Assembly Bill No. 6 from the First Extraordinary Legislative Session (AB 6X) which altered the landscape regarding recovery of ongoing transition costs, prohibiting divestiture of any “facility for the generation of electricity owned by a public utility” prior to January 1, 2006. Under AB 6X, the URG portfolios are once again subject to cost-of-service ratemaking and include much more than the utilities’ contractual obligations. AB 6X also amended existing statutes to delete any reference to the market valuation of the utilities’ generation assets, which had been an essential step in the calculation of the utilities’ uneconomic costs. (Pub. Util. Code, Section 367, subd. (b).)

As we concluded in D. 02-11-022, nothing in AB 6X rescinds the intent of the Commission that all customers, including DL served by Customer Generation, should pay their fair share of the above-market costs of QF and other utility purchased power contracts. The costs still must be recovered even if the underlying semantics have changed. The Settlement is consistent with this result.

The Commission is giving further consideration to issues surrounding the end of the rate freeze, along with the extent and disposition of transition costs left unrecovered. (D.02-01-011, p. 25 (*slip op.*).)⁵⁷ Moreover, the Commission is also giving further consideration to

⁵⁷ Resolution E-3765 has already extended the rate freeze for SCE to recover its 2000-2001 wholesale purchased power undercollection. The Commission has proposed a similar remediation in the U.S. Bankruptcy Court for PG&E, and if adopted by the court, would satisfy this part of AB 1890 for PG&E. Since SDG&E ended its rate freeze before December 31, 2001, this provision of AB 1890 would not apply to it.

what levels of rates and charges are necessary to assure utilities are reasonably creditworthy and financially healthy, in order for utilities to fulfill their responsibility to procure and deliver reliable, safe and adequate electricity. The result may or may not require a continuation of recovery of costs at frozen rate levels.

The timing of the end of the rate freeze, the corresponding impact on transition cost recovery, and the definition of what were formerly considered stranded costs are issues that are being considered in A.00-11-038 et al., in the rehearing of D.01-03-082, as ordered by D.02-01-001. We are also considering in that proceeding the impact of AB 6X and AB 1X on the various provisions of AB 1890. Here, we find that ongoing CTC should be included in the CRS applied to Customer Generation as set forth in the Settlement. This determination may be subject to subsequent adjustment, depending on our further consideration and determination in A.00-11-038 et al., and other related pending proceedings. We do not prejudge or intend to prejudge the outcome of these pending matters in today's decision. Accordingly, we reserve the option of revisiting the treatment of tail CTC as adopted in this order if necessary to conform to any subsequent Commission disposition of the tail CTC issue.

Eastside Power Authority requests that the Settlement Agreement be modified to provide for "the continuation of the CTC exemption for entities provided in Direct Access legislation AB 1890."⁵⁸ To the extent certain parties may have statutory exemptions from CTCs, the Settlement Agreement does not change those statutory exemptions, as explained in

⁵⁸ Eastside Comments, pp. 2-3.

Section 8.1 of the Settlement. Therefore additional language proposed by Eastside is unnecessary.

D. SCE'S Historical Procurement Charge

1. Parties' Positions – Pre-Settlement

In its opening testimony in this phase of the proceeding, SCE proposed to apply the HPC to DL customers on the same basis as was adopted for DA customers in D.02-07-032. The HPC, as adopted in D.02-07-032, provided recovery of SCE's past procurement cost undercollections as measured by the starting balance in SCE's "Procurement Related Obligation Account" (PROACT). Because DL customers affected by SCE's HPC proposal did not receive adequate notice, SCE agreed to withdraw its testimony in the A.98-07-003 proceeding proposing application of the HPC to DL customers. The HPC adopted in D.02-07-032 thus only applied to DA customers.

SCE argues that because the scope of this proceeding has been expanded to include recovery of costs from DL customers, it should be allowed to renew its proposal for application of the HPC to DL customers.

Real Energy and the Joint Parties argue affected DL parties still have had no opportunity to comment or to provide input regarding SCE's HPC because DL issues were specifically excluded from the A.98-07-003 proceeding where the HPC was litigated and adopted. These parties thus opposed SCE's proposal to apply an HPC to DL that was developed in a proceeding where DL was specifically excluded from consideration. These parties contend that SCE has offered no evidence as to what, if any, undercollection costs may have been incurred by DL customers. If the Commission chooses to impose an SCE HPC on DL customers, however,

the parties argue that such charge should only be considered for DL customers that leave the utility system after a final decision is issued in this proceeding. Moreover, the parties argue that no HPC should be imposed against such DL customers absent a showing that some portion of the PROACT balance is attributable to them.

CLECA acknowledges that “departing load customers should pay for their share of past undercollections by both their serving utility and the DWR” and therefore agrees that “the HPC may be appropriate.”⁵⁹ CPA argues, however, that new qualifying Customer Generation falling within the annual MW caps should also possibly be exempt from SCE and PG&E’s historic charges, citing the “state’s expressed need to increase energy supply resources in California and the Commission’s recognition of “distributed generation as a desired new resource.”⁶⁰ Similarly, Capstone argues that small clean distributed generation should be exempted from utility historical costs based on the “offsetting benefits” of such generation.⁶¹

2. Discussion

Various parties categorically oppose any surcharge on DL, including the HPC, based on public policy considerations as outlined previously. No party, however, offered any specific criticisms in comments on the Settlement regarding the HPC recovery treatment proposed in the Settlement. We conclude that Section 7.1 represents a reasonable

⁵⁹ CLECA Comments, p. 4.

⁶⁰ CPA Comments, p. 2, *citing* D.02-10-062.

⁶¹ Capstone Comments, pp. 6–7.

compromise of the positions taken regarding recovery of SCE's HPC, and is consistent with the record and the law. Accordingly, we approve of the Settlement's treatment of SCE's recovery of its HPC from DL served by Customer Generation.

IX. Tariff Filing Implementation

The utilities shall make compliance advice letter filings within 5 business days of the effectiveness of this order, to amend their tariffs to implement the CRS on Customer Generation Departing load as provided for in this order. As noted previously, the bond charge component of CRS shall be implemented separately once this decision becomes final and appealable pursuant to Section 4.3 of the Rate Agreement.

The advice letters implementing the CRS pursuant to this decision shall be effective on filing, subject to post-filing review by the Energy Division. Remittances to DWR pursuant to the Servicing Agreements and Orders are to commence with the receipt of the applicable charges.

X. Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Pub. Util. Code Section 1731(c) (applications for rehearing are due within 10 days after the date issuance of the order or decision) and Pub. Util. Code Section 1768 (procedures applicable to judicial review) are applicable.

XI. Comments on the Alternate Decision of Commissioner Lynch

The Alternate Draft Decision of Commissioner Lynch was filed and served on parties on February 13, 2003. Comments on the Alternate Draft Decision were filed on February 20, 2003, and reply comments were filed

on February 25, 2003. Based on review of parties' comments, we have made certain corrections, clarifications and revisions, as set forth herein.

XII. Assignment of Proceeding

Carl Wood and Geoffrey Brown are the Assigned Commissioners and Thomas Pulsifer is the assigned ALJ in this proceeding.

Findings of Fact

1. Decision (D.) 02-03-055 determined that, as a condition of retaining the DA suspension as effective after September 20, 2001, a surcharge must be imposed on DA customers sufficient to prevent cost shifting to bundled customers as a result of DA migration between July 1 and September 20, 2001.

2. By ALJ ruling dated March 29, 2002, the scope of this proceeding was expanded to consider cost responsibility surcharges for "Departing Load" in order to prevent cost shifting to bundled customers.

3. Pursuant to Rule 51.1, a joint motion was filed for approval of a Settlement Agreement proposing disposition of various contested issues in this proceeding relating to cost responsibility surcharges applicable to Departing Load served by Customer Generation.

4. The Settlement Agreement is offered as an integrated document, and not as a collection of separate agreements on discrete issues. Each party has reserved the right to withdraw support of the Agreement if the Commission makes modifications or makes approval conditional upon modifications.

5. The CRS elements that are at issue for Customer Generation include Department historic and ongoing charges, "tail" CTC charges, and the HPC for SCE.

6. DWR began procuring electricity on behalf of retail end use customers in the service territories of the California utilities: for PG&E and SCE on January 17, 2001, and for SDG&E on February 7, 2001.

7. AB 1X provides for DWR to collect revenues by applying charges to the electricity that it purchased on behalf of all retail customers, as a direct obligation of DWR.

8. Various parties raised concerns that Customer Generation will become uneconomic to develop and be contrary to Legislative and Commission policy should CRS be imposed on CG departing load.

9. The Legislature has codified its preference policy for clean/ultra-clean customer generation through AB28X, AB58, SB1038 and SB2228.

10. The provision for a “tail” CTC covering those cost categories defined in Pub. Util. Code Section 367 (a) (1)-(6), is consistent with Commission and legislative mandates for customers to bear their share of responsibility for the above-market component of utility purchased power and QF contracts.

11. Pub. Util. Code Section 2827 prohibiting a customer from metering gross electricity demand makes it impossible to apply DA CRS to the gross electricity usage of net metered customers.

12. AB117 leaves gives the Commission the discretion to determine the “fare share” of DWR’s electricity purchase costs, as well as electricity purchase contract obligations incurred by DWR.

13. Customer generation that departed from bundled service prior to February 1, 2001, is exempt from any DWR bond charges and ongoing DWR power charges.

Conclusions of Law

1. It is consistent with the intent of D. 02-03-055 to impose cost responsibility surcharges on Customer Generation Departing Load to the extent necessary to prevent cost shifting to bundled customers based on generally similar principles as apply to DA load as set forth in D. 02-11-022, as modified in D.02-12-027.

2. The Commission has broad authority under general provisions of Public Utilities Code Section 701 to regulate public utilities and to “do all things...which are necessary and convenient in the exercise of such power and jurisdiction.”

3. The Commission has authority under AB 1X and AB 117 to impose CRS on Customer Generation Departing Load to recover DWR-related costs.

4. Pursuant to AB 1X, AB 117 and Public Utilities Code Sections 701 and 366(d), as well as the provisions of D. 02-02-051, the Commission has legal authority to apply DWR Bond Charges on Departing Load Customer Generation that departed from utility service after DWR began procuring power on behalf of retail utility customers.

5. Under Rule 51.1(e), the Commission must find a settlement, whether contested or uncontested, to be “reasonable in light of the whole record, consistent with the law, and in the public interest” before it may approve a settlement.

6. The Settlement Agreement offered in this phase of the proceeding is not reasonable in light of the whole record, consistent with the law, or in the public interest.

7. Parties sponsoring the Settlement should be provided an opportunity to elect to accept our denial of the Settlement Agreement or to request other relief, as provided for under Rule 51.7.

In the passage of AB 2228, the Legislature specifically considered and elected to exempt biodigester projects from any net metering or other charges for departing the utility system. Accordingly, CRS should not be imposed on such biodigester projects.

8. It is reasonable to permit eligible customer generation that qualifies for net metered status under Pub. Util. Code Section 2827(b)(2) not to pay DA CRS on the gross electricity usage.

9. AB58 amended Public Utilities Code Section 2827.7 and exempts generation eligible for net metering that has all permits on or before December 31, 2002, and is constructed on or before September 30, 2003, from any new or additional surcharges for the life of the system. Accordingly, CRS should not be imposed on customer generation eligible for net metering.

10. This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date of issuance of the order or decision) and Public Utilities Code Section 1768 (procedures applicable to judicial review) are applicable.

ORDER

IT IS ORDERED that:

1. This order shall apply to the service territories of Southern California Edison, Pacific Gas and Electric Company, and San Diego Gas & Electric Company.

2. A mechanism for the determination of a Cost Responsibility Surcharge applicable to Departing Load served by Customer Generation is hereby adopted, as set forth below.

3. The terms of the Proposed Settlement Agreement regarding the imposition of a surcharge mechanism is not approved.

4. A Direct Access Cost Responsibility Surcharge is hereby adopted applicable to designated departing load in the service territories of PG&E, SCE, and SDG&E composed of the following elements:

- a. DWR Bond Charge, covering cost responsibility for the period from the inception of DWR's power purchase program through September 20, 2001.
- b. DWR Power Charge, covering the historic period from September 21, 2001, through December 31, 2002.
- c. DWR Power Charge, covering the prospective period for the Calendar Year 2003.
- d. Utility-Retained generation component applicable to above-market costs

5. Consistent with Public Utilities Code Section 2827, customer generation eligible for net metering shall be exempt from the DA CRS adopted in this order on gross usage. Net metered customers shall

continue to pay for all applicable charges based on the net energy consumption as defined in existing tariffs.

6. 350 MW of clean and super-clean distributed generation as defined in Public Utilities Code Section 353.2 (b).

7. DWR ongoing power charge shall be set equal to the corresponding cents/kWh surcharge component in effect on the date of departure as determined pursuant to the DA phase of R. 02-01-011 and related or successor proceedings.

8. To the extent that the Commission determines that (a) any Commission-imposed DA CRS cap has resulted in an undercollection by the utility of any applicable DA nonbypassable charges, and (b) individual DA customers shall remain responsible for a portion of the undercollection if they return to bundled utility service, then these DA customers shall remain responsible for the same portion of the undercollection when they become Departing Load.

9. At the discretion of the departing direct access customer, the undercollected amount referenced above shall be collected through either a lump sum or through monthly billings by the utility with the total amount of each monthly charge for both DA undercollections and any applicable Departing Load surcharges subject to the DA CRS cap.

10. SCE is authorized to recover a Historical Procurement Charge (HPC) from Departing Load that was receiving bundled service at the time of the departure.

11. Departing Load exempt from competition transition charges pursuant to any statute, including without limitation Public Utilities Code

Sections 372 and 374, as the statute exists on the day this order is adopted, shall be exempt from “tail” CTC.

12. Parties sponsoring the Settlement are authorized, as part of their comments of the Alternate Decision, to request other relief, as provided for under Rule 51.7.

13. The recovery of the CRS element relating to recovery of bond charges shall be implemented once this decision becomes final and unappealable. During the interim, the bond charge component shall be tracked through the subaccount process established in D. 02-10-063 and D. 02-11-074.

14. PG&E, SCE, and SDG&E, respectively, are hereby directed to file necessary tariff revisions to incorporate and implement the other surcharge elements adopted in this order. The utilities shall make compliance advice letter filings within 5 days of the effectiveness of this order, to implement the CRS element, other than bond charges, as adopted in this order. The advice letters shall be effective on filing, subject to post-filing review by the Energy Division.

This order is effective today.

Dated _____ in San Francisco, California.